part 7

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Frost

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Nathan J. Frost

Title: Director – New Technology and Energy Conservation

Summary:

Company Witness Nathan J. Frost details the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "GT Plan"). Mr. Frost also addresses the elements detailed in the Final Order issued in the 2018 GT Plan proceeding ("2018 Final Order"), and discusses the proposed deployment of AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order, as well as the Company's initiatives related to electric transportation.

In terms of AMI, Mr. Frost testifies that the Company is proposing to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. As Mr. Frost testifies, nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Mr. Frost also discusses the proposed opt-out policy. As Mr. Frost explains, while Dominion Energy Virginia fully supports AMI and the benefits it provides, the Company understands that some customers may prefer not to have a smart meter and plans to accommodate those customers where practical, if deemed necessary by the Commission. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. As Mr. Frost testifies, the Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral.

In terms of electric transportation, Mr. Frost describes the proposed Smart Charging Infrastructure Pilot Program, under which the Company would offer rebates for incentives for infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Mr. Frost additionally testifies as to the Company's education plan. The overarching goal for the plan is to educate customers, to raise awareness and understanding of the benefits of the GT Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of the GT Plan. The plan specifically addresses education for full deployment of AMI and the Smart Charging Infrastructure Pilot Program, consistent with the 2018 Final Order.

DIRECT TESTIMONY
OF
NATHAN J. FROST
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, business address, and position of employment.

A. My name is Nathan J. Frost and my business address is 600 East Canal Street, Richmond, Virginia 23219. I am Director of New Technology and Energy Conservation for Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"). A statement of my background and qualifications is included as Appendix A.

Q. Please describe your area of responsibility with the Company.

A. I am responsible for delivering advanced metering and demand side management solutions for Dominion Energy Virginia. I am also responsible for integrating new technologies and developing renewable energy and energy conservation programs within the Company's regulated service territory.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to detail the Company's plan for full deployment of smart meters and the associated infrastructure (together "AMI") as part of its proposal to transform its electric distribution grid (the "Grid Transformation Plan," "GT Plan," or "Plan"). I will specifically address the elements detailed by the State Corporation Commission of Virginia (the "Commission") in its Final Order dated January 17, 2019, in Case No. PUR-2018-00100 (the "2018 Final Order"), and I will discuss the proposed deployment of AMI, including detailed cost estimates for the investments proposed during 2019, 2020, and 2021 ("Phase IB"); the proposed opt-out policy; and the Company's plan for customer education consistent with the 2018 Final Order.

I will also discuss the Company's initiatives related to electric transportation, including the Smart Charging Infrastructure Pilot Program that the Company proposes as part of the GT Plan, as well as customer education proposals.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, NJF, consisting of Schedules 1 through 10, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	Cost Schedule
2	Sample Smart Meter Post Card
3	Sample Smart Meter Door Hanger
4	Current Opt-Out Customer Information Package
5	Proposed Opt-Out Policy
6	Opt-Out Fee Breakdown
7	Proposed Update to Terms and Conditions
8	Opt-Out Fee Comparison
9	Navigant Forecast for Electric Vehicles
10	Department of Energy EVI-Pro Lite Tool Results

Additionally, I sponsor Filing Schedule Frost, Attachments A through C, which provide summaries of executed contracts and request for proposals ("RFP") from which detailed pricing estimates were prepared. The table below provides a description of these filing schedules:

Filing Schedule Frost	Description
Extraordinarily Sensitive Attachment A	RFP Summary for Meter Purchases
Extraordinarily Sensitive Attachment B	RFP Summary for Meter Exchange Vendors
Extraordinarily Sensitive Attachment C	RFP Summary for Workplace Charging

Other supporting documents include:

- AMI Master Service Agreement

This document is not included with my filing schedules due to its voluminous nature; however, the Company will make this document available electronically.

I also sponsor certain sections of the Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document. Finally, I sponsor the metrics categories as identified in Company Witness Edward H. Baine's Schedule 2.

Q. Did you provide information to West Monroe Partners, LLC ("West Monroe") for use in the cost-benefit analysis ("CBA")?

A. Yes, I provided costs and additional inputs for AMI, electric transportation initiatives, and customer education to West Monroe for use in the CBA. I also support the benefits reflected in Company Witness Thomas G. Hulsebosch's Schedule 2, as identified therein.

The specific costs I support in Phase IB are:

Nominal $, in Millions	**2019**	**2020**	**2021**	
	Year 1	**Year 2**	**Year 3**	**3-year Total**
Phase IB	$17.2	$83.1	$120.4	$220.8
Capital	$14.9	$73.3	$102.7	$190.8
O&M	$2.4	$9.8	$17.8	$29.9

My Schedule 1 provides detailed cost information for the GT Plan components that I sponsor.

Q. Mr. Frost, how is your testimony organized?

A. My direct testimony is organized as follows:

I. Smart Meter Deployment

- A. Existing System, Need, and Proposed Deployment Plan
- B. Cost Estimates
- C. Benefits of AMI
- D. Alternatives Considered
- E. Customer Education
- F. Opt Out

II. Electric Vehicles

- A. Existing System, Need, and Proposed Deployment Plan
- B. Cost Estimates
- C. Benefits of Smart Charging Infrastructure Pilot Program
- D. Alternatives Considered
- E. Customer Education

III. Conclusion

I. SMART METER DEPLOYMENT

Q. Please provide a brief overview of the Company's plan to deploy AMI as part of the Grid Transformation Plan.

A. Dominion Energy Virginia proposes to fully deploy AMI across its service territory. Through this technology, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. The full deployment of AMI is a foundational component of the Grid Transformation Plan, effectively enabling all other Plan components. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, in reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. Does the full deployment of AMI meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?

A. Yes, the definition of "electric distribution grid transformation project" in Va. Code § 56-576 specifically includes "advanced metering infrastructure."

Q. You mentioned that you will address elements related to AMI required by the 2018 Final Order. What are those elements?

A. In the 2018 Final Order, the Commission denied the Company's proposal to fully deploy AMI, but did so without prejudice to the Company seeking approval of the deployment in future petitions in compliance with requirements set forth in the 2018 Final Order. The Commission specified the elements related to AMI deployment that the Company should include if it chooses to pursue the deployment on pages 10-11 of the 2018 Final Order:

> If Dominion [Energy Virginia] chooses to proceed with a proposal for full deployment of AMI, its next proposal should be supported by a detailed and comprehensive plan for evaluation that addresses, at a minimum, the following elements:
>
> a. Detailed cost estimates for all AMI-related spending.
>
> b. Any plan for time-varying rates; and whether any such offering would be the default tariff for a customer with an installed smart meter.
>
> c. Any customer "opt-out" provision, both as to smart meter installation and time-varying rates, under all tariff scenarios for those consumers who so choose and to protect particularly vulnerable customers, such as those with medical conditions that reduce their ability to manage energy usage; and any fees proposed by the Company to be charged to customers who choose to opt-out both as to time-varying rates and smart meter installation.

d. Analysis of how any plan promotes demand response, energy efficiency, and conservation.

e. A transition plan including adequate customer education.

The full deployment of AMI is foundational to the Grid Transformation Plan and many other Company initiatives. My testimony will address each of these elements, as well as other relevant information to prove that the full deployment of AMI is reasonable and prudent.

Q. On page 12 of the June 27, 2019 Final Order in Case No. PUR-2018-00065 ("2018 IRP Final Order"), the Commission ordered the Company in future integrated resources plans ("IRPs") to "systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment." (Internal footnotes omitted.) Although this is not an IRP proceeding, does your testimony address these requirements as they relate to AMI?

A. Yes, I will discuss each of these items. I will also discuss the proposed deployment plan for AMI, the proposed opt-out policy, and the Company's plan for customer education consistent with the 2018 Final Order.

A. Existing System, Need, and Proposed Deployment Plan

Q. What is the current make-up of the meter population across Dominion Energy Virginia's service territory?

A. Dominion Energy Virginia serves approximately 2.54 million customer accounts in Virginia. As of July 1, 2019, approximately 78% of Virginia customer meters were automated meter reading ("AMR") meters, approximately 17% were smart meters, and approximately 5% were manually read meters. Section III.D of the Plan Document provides details on these meters and how they function.

Q. What is the need driving the full deployment of AMI?

A. The full deployment of AMI is needed to enable the functionality of a transformed grid and to meet the needs and changing expectations of our customers. The Company's existing AMR meters have served the Company and its customers well but have functional limitations. The existing AMR meters:

- Cannot provide interval energy usage data or demand readings, without which the Company cannot effectively provide detailed usage information to its customers nor offer more advanced rate options like time-varying rates;
- Cannot capture operational conditions in real time or on demand, such as outage information and meter tampering;
- Cannot provide real-time premises level voltage, which is critical to integrating distributed energy resources ("DERs") and enabling advanced analytics;
- Cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests.

Q. What is AMI and how does it function?

A. The term AMI, or "advanced metering infrastructure," refers to the over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

Smart meters are electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information. Examples of the information captured by smart meters include energy usage, demand, voltage, and meter temperature, as well as other real-time information regarding the operational status, self-diagnostics, power quality, and condition of the electric grid at the customer premises—enabling the meter to function as an end-of-line sensor at the customer premises.

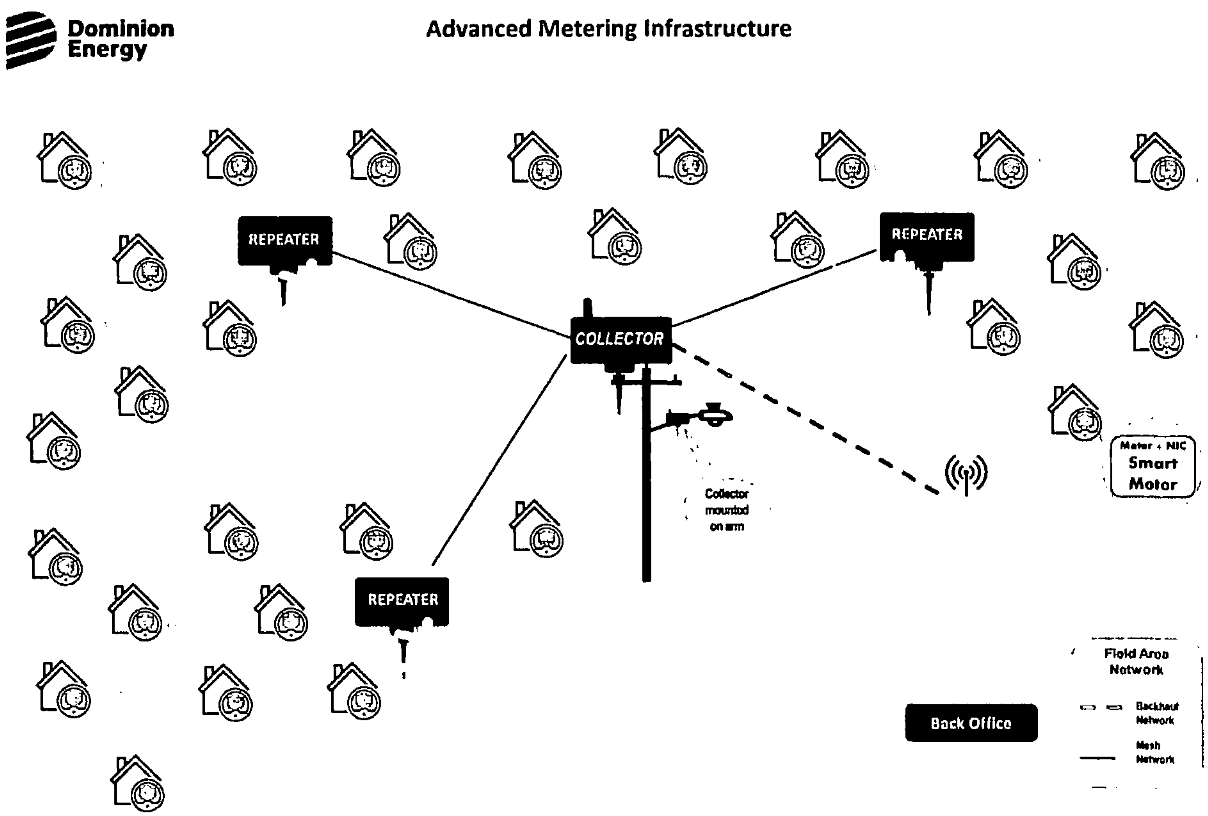
Smart meters are equipped with a network interface card ("NIC") and communicate with each other, creating what is referred to as a mesh network. The higher the density of smart meters, the stronger the mesh network.

A system of field telecommunications devices—comprised of devices called repeaters and collectors—gathers meter data from the mesh network and transmits the data gathered back to the utility through a backhaul network. Together, the mesh and backhaul networks are called the field area network.

A head-end system receives and processes the data and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The head-end system also provides information from smart meters to other Company operating and analytical systems such as the meter data management system, the customer information system, and the outage management system, including valuable, real-time information regarding the operational status and condition of the electric grid at the customer premises.

Figure 1 provides a visual representation of the components of AMI and how they depend on each other to function.

Figure 1: Advanced Metering Infrastructure



Q. Does the Company have experience with AMI?

A. Yes. In 2008, the Company began to deploy AMI technology in a targeted fashion based on specific operational and customer needs. The Company did this at a measured pace over the course of several years during which time we refined our expectations of supplier and technology capabilities and developed operational experience through realworld application. Following a competitive bidding process, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of our service territory in order to validate deployment and operational strategies. The Company used the knowledge gained from this limited deployment of AMI to develop its strategy for full deployment across the service territory.

Q. How does the Company propose to deploy AMI throughout the service territory?

A. The Company expects to complete deployment of AMI over a six-year period beginning in 2019. During this time, the remaining approximately 2.1 million smart meters and 3,100 network devices will be deployed in a structured manner across the Virginia service territory office-by-office, with deployment occurring in multiple offices at the same time.

Within each office, the first step is to establish the field area network by deploying network devices (*i.e.*, repeaters and collectors). Next, the deployment of smart meters occurs, which fills in the mesh network, resulting in a robust, secure, and reliable network for two-way communication. As smart meters are deployed, their levels of communication and performance in the context of the growing AMI footprint are monitored and measured against established criteria. After the installation of smart meters in a given office is complete, a period of network optimization will take place where communication levels are measured, and additional network devices may be deployed to further bolster communications.

Table 1 details the projected plan for full deployment of AMI as measured by the number of smart meters installed in a given office.

Table 1: Smart Meter Deployment Plan

Region	Office	2019	2020	2021	2022	2023	2024	Total
Central	Richmond	40,000	124,000	2,000				166,000
Northwest	Orange	11,000						11,000
Eastern	Williamsburg		51,000					51,000
Eastern	Norfolk		58,000	43,000	1,000			102,000
Eastern	Peninsula		103,000	74,000	2,000			179,000
Central	Petersburg		40,000	62,000	3,000			105,000
Eastern	VA Beach			188,000	11,000	3,000		202,000
Central	East Richmond			80,000	19,000	2,000		101,000
Eastern	Chuckatuck			64,000	65,000	2,000		131,000
Northwest	Woodbridge			40,000	55,000			95,000
Northwest	Warrenton				33,000			33,000
Central	Midlothian				118,000	29,000	1,000	148,000
Northwest	Leesburg				81,000	1,000		82,000
Central	Fredericksburg				79,000	32,000		111,000
Eastern	Chesapeake				75,000	2,000		77,000
Northwest	Fairfax				15,000	107,000	1,000	123,000
Central	Southside					19,000		19,000
Northwest	Blue Ridge					61,000		61,000
Central	Farmville					25,000		25,000
Central	Altavista					14,000		14,000
Northwest	Rockbridge					15,000		15,000
Central	South Boston					20,000		20,000
Northwest	Springfield					40,000	97,000	137,000
Central	Northern Neck						24,000	24,000
Northwest	Alleghany						14,000	14,000
Central	Gloucester						44,000	44,000
Northwest	Shenandoah						20,000	20,000
	TOTALS	51,000	376,000	553,000	557,000	372,000	201,000	2,110,000

For simplicity, the totals represent rounded figures. A very small sub-set of meter replacements may require special equipment and handling that may cause actual completions to fall outside of the years indicated above.

Q. What was the rationale used to determine this deployment plan?

A. The major determining factors for the full deployment plan were metering operations efficiency, deployment efficiency, and geographic diversity. Looking first at operations, the Company analyzed which areas in its service territory require the highest number of truck rolls for basic meter-related service order types. Such requests can be performed remotely once AMI is deployed, and fewer truck rolls will lead to lower cost of service components and reduced greenhouse gas emissions. The Company prioritized field offices based on this analysis; offices that would experience the largest reduction of truck rolls, like Norfolk, Peninsula, and Petersburg, were pulled forward in the deployment plan.

The Company also considered deployment efficiencies in developing its plan. Deploying an entire office and then neighboring offices improves efficiencies for deployment resources and allows support resources to train in one area on the new technology before starting up a team in another area. Additionally, as mentioned previously, smart meters communicate with each other to form the mesh network. Without a strong mesh network, smart meters cannot communicate with the backhaul network. And without the mesh and backhaul network, no two-way communications between the Company and the customers' smart meter exist to enable meter reading and remote functionality or any of the other benefits associated with smart meters. For these reasons, the Company has and proposes to continue to deploy AMI office-by-office, which will ensure operational efficiency and cost effectiveness.

Finally, the Company also incorporated geographic considerations into the deployment plan, ensuring that each of its three regions has deployment activity by 2021, but giving early preference to Central and Eastern regions based on the focus of previous deployments in Northwest region and the truck roll reduction potential in these areas.

Q. Table 1 shows a number of smart meters being deployed in 2019. Why is that?

A. The Company had ordered approximately 60,000 smart meters prior to the 2018 Final Order to further the deployment of the existing 435,000 meters in the field, to keep vendors engaged, and to maintain experience with the most recent technological developments in the industry. We believe that these installations were in the best interest of our customers and are optimistic that the Commission will see the value of the investment.

Q. Will any operating systems be retired or replaced as a result of full AMI deployment?

A. The Company plans to use the AMI head-end system currently in place for the full deployment of AMI. This system has proven to meet the functional and technical specifications of Dominion Energy Virginia, and will scale to support expanded capacity in alignment with the planned rollout of smart meters. The Company will upgrade the system as needed as the deployment of smart meters progresses and as the Company enables additional AMI capabilities. Additionally, the Company plans to retire the AMR head-end and associated systems.

B. Cost Estimates

Q. What are the projected investment levels for AMI deployment during Phase IB of the Grid Transformation Plan?

A. Table 2 shows the Company's anticipated capital and operations and maintenance ("O&M") investments for the deployment of AMI during Phase IB. Table 2 is an excerpt from my Schedule 1. As described by Company Witness Gregory J. Morgan, the Company has committed to the investments related to AMI in Phase IB being recovered through its existing rates for generation and distribution services ("base rates").

Table 2: Phase IB Estimated AMI Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years*	
Capital	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
$14.9	$1.9	$71.9	$3.0	$100.3	$4.6	$187.0	$9.6

* Three year totals may not add due to rounding.

Q. **What is the Company's total projected investment for AMI deployment?**

A. As shown in Schedule 1, the Company anticipates an estimated $394.4 million in capital investment and $53.9 million in O&M investment for the full deployment of AMI over the 10-year GT Plan period.

Q. **How did the Company develop these estimates?**

A. The Company developed these cost estimates based on competitively negotiated contract pricing for various project components, along with current system information on quantity, type, and location of meters, engineered solutions for AMI field network design by deployment area, current and future internal labor rates, contracts for cellular backhaul network communications, and call center operations historical and projected costs. Our previous experience deploying AMI informed the cost estimates.

Q. **Please discuss the competitively negotiated contracts you mentioned.**

A. In 2011, the Company conducted a competitive bidding process for the overall AMI systems vendor, including the back office system (*i.e.*, the head-end system), network devices (*i.e.*, repeaters and collectors), network device installation, and smart meter purchases. This process resulted in the selection of Itron Networked Solutions, Inc.

("INSI"), formerly known as Silver Springs Network or SSN. In 2018, the Company went through a process with INSI to transition our AMI head-end system to the cloud, resulting in a new 10-year contract with updated pricing based on our current full deployment plans. The Master Service Agreement ("MSA") and all associated addendums, including the 2018 Statement of Work associated with conversion to the cloud, which are voluminous in nature, will be made available electronically. In addition to an updated contract, transitioning to the cloud provided the Company with cost savings associated with our network and data center infrastructure, which would have otherwise needed upgrading in order to support the full deployment of AMI. Additionally, an enhanced level of support from INSI is available now that the system is hosted in their cloud environment, providing further labor savings to the Company.

In 2019, the Company decided to separate smart meter purchasing efforts from the MSA. The Company conducted an RFP for smart meter purchasing, as described in Filing Schedule Frost, Attachment A. Based on the results of the RFP, the Company decided to use multiple meter suppliers in order to reduce the risk associated with single source supply, to ensure access to new features as they become available, and to maintain competitiveness in pricing. The Company expects to sign contracts with multiple suppliers in the coming months.

Throughout our initial deployment of AMI, the meter exchange vendor has been procured through a competitive bidding process. In 2019, the Company conducted another RFP for meter exchange contractors in order to ensure we have the best partner and most competitive pricing for full deployment. The 2019 RFP is described in Filing Schedule Frost, Attachment B. The Company expects to sign a contract with the chosen supplier in the coming months.

Q. Have these projected costs been incorporated into the CBA presented by the Company in this proceeding?

A. Yes, I have provided my Schedule 1 to Company Witness Thomas G. Hulsebosch from West Monroe, who has included them in the CBA.

C. <u>Benefits of AMI</u>

Q. What are the benefits of full AMI deployment?

A. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Quantitative benefits from full deployment of AMI include (i) O&M savings; (ii) avoided capital; and (iii) other benefits in the form of reduced bad debt expense, reduced energy diversion, and improved meter reading accuracy. Additional benefits also result from AMI, including reduced greenhouse gas emissions and economic development.

The full deployment of AMI, combined with the proposed customer information platform ("CIP"), also enables broad deployment of time-varying rates and enhances demand-side management ("DSM") programs, leading to energy and demand savings. Together with West Monroe, the Company has quantified these benefits and included them in the CBA to show the value of full deployment of AMI to customers.

In addition to the quantifiable benefits directly related to AMI, smart meters function as end-of-line sensors, generating essential real-time, premises-level data points. Combining these capabilities of AMI with the grid improvement investments discussed by Company Witness Robert S. Wright, Jr., will provide new and valuable insights, correlations, and trends that will, among other things, detect distribution equipment issues proactively and support circuit automation, dynamic circuit reconfiguration, and distribution asset and device monitoring.

In addition to the benefits quantified and shown in the CBA, many qualitative benefits result from the full deployment of AMI, including improved customer experience, reduced hazard exposure for employees, enhanced load forecasting, and enhanced cost of service studies. Other qualitative customer engagement benefits rely on the combination of AMI and CIP.

The benefits of full AMI deployment are perhaps best understood by looking at the functional capabilities of AMI.

Q. What are the foundational capabilities of AMI?

A. Foundational capabilities of AMI include: (i) remote meter reading; (ii) remote connect / disconnect; (iii) "found ons"; (iv) meter alerts; and (v) detailed energy usage data (*i.e.*, interval data). The Company has enabled these capabilities and has seen the resulting benefits in the limited population of AMI already deployed in its service territory. The benefits of these capabilities will grow with the expanded deployment of AMI across our service territory.

Q. Please explain the remote meter reading capability of AMI and describe the associated benefits.

A. With AMI, the Company can remotely read smart meters. As of June 30, 2019, we have completed over 78 million daily reads this calendar year. Our success rate is 99.84% for remote daily reads for this time period, meaning we get a daily read for every smart meter 99.84% of the time. AMI remote reading capability has out-performed non-AMI based reading methods. For example, for the month of May 2019, the read rates for AMR and manually read meters were 99.2% and 96.2%, respectively, meaning we get monthly reads for all AMR meters 99.2% of the time and for manually read meters 96.2% of the time.

Remote meter reading leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to retrieve and process readings from non-AMI meters, or re-readings when the data was missed on the first attempt. In addition, remote meter reading will lead to billing process improvements, driving out inaccuracies and process exception handling. The remote meter reading capability also leads to avoided capital; specifically, the Company will avoid the additional capital associated with AMR-related equipment and systems.

Remote meter reading also provides qualitative benefits in the form of reduced estimated bills and leads to an improved customer experience. Remote meter reading also means that fewer trucks are on the road, resulting in lower fuel usage and greenhouse gas emissions and less hazard exposure for our employees.

Q. Please explain the remote connect / disconnect capability and describe the associated benefits.

A. AMI allows the Company to remotely connect and disconnect electric service from most customer premises, reducing the need for meter servicing personnel to visit customer premises. With the existing population of smart meters on our system, the Company has avoided over 82,000 truck rolls to complete these types of service orders so far this year, equating to approximately 19.3% of all service orders of this type across our system. Once AMI is fully deployed, the Company anticipates that approximately 75,000 service orders of this nature will be completed remotely each month.

Remote connect / disconnect leads to O&M savings because the Company will no longer have expense associated with the people and the vehicles needed to complete these orders for non-AMI meters. This AMI capability also reduces bad debt expense. By reducing the number of calendar days between a disconnect order and its execution, the balance of past due charges and associated fees is more manageable for customers to resolve. As of June 30, 2019, year-to-date, the average customer bad debt amount for AMI customers was $378 versus $686 for non-AMI customers.

Similar to remote meter reading, remote connect / disconnect provides qualitative benefits in the form of an improved customer experience, particularly associated with move in / move out activities, reduced greenhouse gas emissions, and reduced hazard exposure for Company representatives.

Q. Please explain the "found on" capability of AMI and describe the associated benefits.

A. The Company uses AMI during storm restoration to identify premises that have had power restored but that the system still shows as an outage, which the Company refers to as "found ons." Operators can "ping" smart meters from the back office to determine if power is on and, if so, can close the outage work orders proactively.

The "found on" capability enabled by AMI leads to O&M savings because the Company will no longer have the expense associated with sending trucks to locations where power has already been restored. Data from the existing AMI footprint shows that the number of "found ons" during outage events is reduced by 80% with AMI. In addition to eliminating unnecessary truck rolls, this capability allows crews to focus on locations that actually require line work for service restoration, leading to faster overall restoration for all affected customers.

Q. Please explain the meter alerts available with AMI and describe the associated benefits.

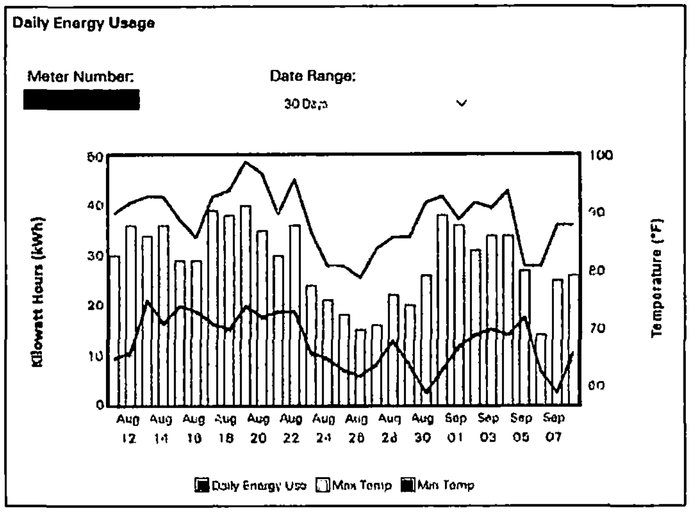
A. AMI meters generate alerts that are communicated to the head-end system, enabling back office personnel to monitor the status of power at the customer premises and generate orders for field investigation when necessary. For example, these alerts can show usage irregularities indicating unauthorized tampering with the Company's metering equipment ("energy diversion"), high internal meter temperature indicating a potential problem with Company or customer equipment, and voltage anomalies indicating operational issues.

Meter alerts lead to O&M savings in the form of reduced energy diversion. In addition to O&M savings, meter temperature alerts from smart meters have generated field visits to investigate operating conditions prior to equipment failure, which has avoided outages and potential damage to equipment and property.

Q. AMI collects and transmits detailed energy usage data (*i.e.*, at a 30-minute interval level). What benefits flow from this data?

A. Having detailed energy usage data unlocks many benefits for the Company and its customers. For customers, this data shows usage patterns, which help them to better understand their bill and to identify ways to reduce usage. For example, the Company has developed a daily graph of usage and weather-related data, which is available to those customers with AMI meters. An example is shown in Figure 2.

Figure 2: Daily Graph of Usage and Weather Data



Additionally, the Company has developed a pilot high usage alert program for its existing AMI customers where enrolled customers receive text or email alerts in near-real time when their energy usage for the day exceeds a kilowatt-hour threshold set by the customer. In the future, with the proposed CIP, the Company can offer high bill alerts, which translate usage data to estimated dollars, and prepay, which is discussed in more detail later in my testimony.

Detailed energy usage data is particularly helpful for net metering customers to understand the details of the energy received and exported at their homes, and how that translates to their net charge each month.

Combined with the proposed CIP, this data will enable the Company to broadly offer time-varying rates and will enhance DSM initiatives, which can lead to significant bill savings and reduced system costs. I will discuss both time-varying rates and DSM initiatives later in my testimony.

In addition to the benefits that detailed energy usage data provides for customers, this data also enables a host of benefits to the Company's operations, including enhancing the Company's load forecasts used in the Company's planning processes. In addition, this data enhances cost of service studies by informing the assignment of revenue and the allocation of costs.

Q. **You have discussed the foundational capabilities of AMI from which the Company has already seen the benefits. What other capabilities of AMI does the Company plan to enable or enhance in the future?**

A. In the future, the Company plans to enable or enhance: (i) remote transition to net metering; and (ii) enhanced voltage data collection.

Q. **Please explain the remote transition to net metering capability and describe the associated benefits.**

A. Today, when a customer requests to net meter, the Company must visit the premises and exchange the existing meter once the customer has installed his or her solar system and passed inspection. This is true even in the case where the new net metering customer already has a smart meter. The Company plans to implement programming to enable remote over-the-air transitioning of the existing smart meter to a net meter upon customer completion of the net metering application process.

Remote transition to net metering will lead to O&M savings in the form of reduced expense associated with the people and the vehicles needed to complete these orders. This capability will also improve the customer experience, reduce greenhouse gas emissions, reduce hazard exposure for our employees, and ultimately facilitate the integration of DERs.

Q. **Please explain the enhanced voltage data collection capability of AMI and describe the associated benefits.**

A. The Company plans to upgrade its AMI head-end system to include a software module associated with voltage data collection and analysis. Enhanced voltage data collection from AMI combined with the system investments discussed by Company Witness Robert S. Wright, Jr., will enable the Company to model the behavior of DERs and perform other analytics, and will enhance feeder voltage optimization. Company Witness Wright describes these benefits.

Q. **As you mentioned, and as the Commission noted in the 2018 Final Order, the full deployment of AMI enables the Company to broadly offer time-varying rates. Does the Company plan to offer time-varying rates after full deployment of AMI?**

A. Yes, we do. The Company is in the process of developing time-varying rates that will leverage AMI both during and after deployment. Company Witness Morgan describes the Company's plans related to time-varying rates. He also addresses the direction provided in the 2018 Final Order related to opt-in and opt-out options for such rates.

Q. **Does full AMI deployment enable a prepay program?**

A. Yes. Full AMI deployment combined with the new CIP will enable the Company to develop a prepay program. Prepay is a program that allows customers to make an up-front payment of their energy bill that will then be reduced over time based on their ongoing usage. Customers will receive alerts as their balance is depleted, and can take action accordingly. In other words, prepay allows customers to manage their energy usage within their budget. In the industry, prepay programs have also been shown to result in energy savings.

Q. You also mentioned that AMI will enhance the Company's DSM initiatives. Please discuss.

A. The Company intends to leverage AMI to enhance DSM initiatives in its service territory. To that end, in March 2019, the Company issued an RFP for DSM programs that included a request for information about the degree to which AMI could enhance program operations. The responses generally state that broad deployment of AMI would provide information that could be used to more effectively target the most appropriate customers for specific programs and would provide better recommendations for energy savings within any program that involves a behavioral or educational component. In addition, broad deployment of AMI would provide information that could be used to enhance the evaluation of program effectiveness and would enable, in conjunction with a new CIP, implementation of a future peak-time rebate ("PTR") program.

Q. Please explain how a PTR program would work.

A. PTR is a customer program designed to target and reduce the Company's coincident peak period. The Company would call a certain number of PTR events per year, each lasting for a certain number of hours. For example, the Company could call ten four-hour events per year to cover projected coincident peak periods. Once called, enrolled customers would receive a notification of the opportunity to reduce usage, and would earn a rebate if they reduce usage during the PTR event. Customers would not be penalized if they do not reduce usage during the event.

Q. Aside from enabling DSM programs that leverage AMI, does full AMI deployment provide other benefits to the Company's DSM initiatives?

A. Yes, AMI also provides a significant benefit to the evaluation, measurement, and verification ("EM&V") requirements of DSM programs and further supports DSM operations. For EM&V, AMI provides detailed energy usage data from each customer endpoint where smart meters are deployed. Operationally, for customers enrolled in current peak-shaving programs, AMI can provide data indicating load curtailed at the metering points of participating customers in near-real time.

In sum, the Company fully plans to leverage the full deployment of AMI to promote demand response, energy efficiency, and conservation.

D. Alternatives Considered

Q. What alternatives to the proposed deployment of AMI did the Company consider?

A. The Company considered not expediting AMI deployment, as proposed here, but continuing a slow rollout as we have done for the last several years. Given the aging state of our non-AMI meters and systems today and the amount of investment that would be needed to maintain their viability, as well as the lack of support the legacy meters and systems provide for many grid transformation initiatives, the Company felt that this was no longer a viable deployment approach. A slower rollout of AMI delays benefits and may eliminate the benefit of some avoided capital expense altogether.

Q. Did the Company consider alternative AMI systems?

A. Yes. In 2008, the Company piloted the Elster AMI system. At that time, Elster was an industry leader in AMI systems for large utilities. Elster's AMI technology was proprietary, meaning only its smart meters could be used with its network and back office system. The Company evaluated the Elster system for applications involving commercial and industrial complex meters, rugged and expansive terrain (*e.g.*, mountain, valley, rural), and dense populations (*e.g.*, urban).

The period of 2008 to 2010 saw rapid changes in AMI technology, with many new vendors entering the market. In 2010, the Company issued a request for information ("RFI") to collect information on additional AMI systems available in the market. This research resulted in the Company issuing a competitive RFP in 2011 to select new AMI systems and smart meter vendors.

During this process, the Company focused on potential vendors' relevant experience, competitive pricing, and overall capabilities. From a systems and technology perspective, technical selection criteria focused on security, network reliability, and technical performance; scalability potential; and technical and functional requirements. The Company also had a preference to select an AMI partner that would allow for diversity in smart meter suppliers, and wanted to ensure that the selected technology would not become obsolete in the medium and long term. From this RFP, the Company selected its AMI systems vendor, INSI (formerly Silver Springs Networks).

Q. Does the Company have any concerns related to the potential premature obsolescence with the selected AMI technology?

A. No. The Company is not concerned with premature obsolescence of the chosen AMI technology based on the status of AMI deployment across the United States; the research published by third parties and industry experts; and the technology features and capabilities, including specific feedback and assurances from the vendors. Company Witness Hulsebosch provides further details regarding AMI technology from an industry perspective.

E. Customer Education

Q. The 2018 Final Order required information on a transition plan to AMI, including adequate customer education. How does the Company plan to educate customers in connection with the full deployment of AMI?

A. Fully deploying AMI across the service territory provides the Company with the unique opportunity to interact directly with 2.1 million customers over the next six years. To ensure that the customer experience associated with the meter exchange is a positive one, the smart meter deployment team will be executing an outreach and education strategy, to include targeted communications to each customer prior to and during the installation phase of the new smart meter. These types of communications will be delivered through several channels, including direct mail, door hangers, social media, web, mobile, and public presentations. Customer communications will alert customers of the upcoming meter exchange, direct customers to the website for frequently asked questions, and provide options for setting an appointment for property access if needed. Examples of direct mail and door hangers can be found in my Schedules 2 and 3.

Additional post-deployment communications and outreach will also serve as a mechanism to educate and inform customers on benefits of their smart meter. Post-deployment outreach will include educating customers on tools already available to smart meter customers, and to new tools and applications as they become available. For more information on post-deployment customer education, please refer to Section VI.A.7 of the Plan Document.

Q. Is customer education related to the GT Plan necessary beyond the full deployment of AMI?

A. Yes. Because the Grid Transformation Plan is comprehensive and offers such a wide variety of benefits to all customer types, customer education appropriately extends to multiple GT Plan elements beyond smart meters. Accordingly, the Company will focus on educating customers about the entire grid transformation process, associated projects and investments, and about when and how they can fully utilize the new capabilities of the transformed distribution grid. This GT Plan-related customer education plan supplements the Company's overall efforts to educate its customers from topics ranging from available rate schedules to general energy education.

The Company's customer education plan for the GT Plan, which I sponsor, is attached to the Plan Document as Appendix F. The overarching goals for this plan are to educate customers, to raise awareness and understanding of the benefits of the Grid Transformation Plan investments, and to encourage participation in future programs and offerings to fully maximize the benefits of GT Plan. This will be accomplished by the Company's commitment to deliver concise, consistent, easy-to-understand content via multiple external communications channels, including but not limited to, website content, social media, digital and direct mail, bill inserts and newsletters, presentations and public events, video and display signage, media coverage through local and regional news outlets and interactions with the customer service organization.

F. <u>Opt-Out Policy</u>

Q. The 2018 Final Order required information on any opt-out policy related to smart meter installation. What is the Company's position related to customers opting out of the smart meter deployment?

A. The Company fully supports AMI and the benefits it provides, and believes all customers should have a smart meter. Accordingly, the Company has developed a comprehensive customer education plan. Nevertheless, the Company understands that some customers may prefer not to have a smart meter and we plan to accommodate those customers where practical if deemed necessary by the Commission.

Q. Please describe the process involved when a customer opts out of smart meter deployment.

A. When a customer opts out of smart meter installation, the Company must expend additional resources both initially and on an ongoing basis. Up front, the Company must create an opt-out version of the meter—a smart meter with the communications device removed. The Company must then install that meter. There are also administrative expenses associated with a customer's initial decision to opt out of smart meter installation, such as program administration and reporting, customer communications and account management, work order generation and scheduling, inventory management and shipping. On a monthly basis, the Company must send a meter reader to manually read the non-communicating meter.

Q. What is the Company's current opt-out practice for smart meters?

A. Currently residential customers on Rate Schedule 1 with accounts in good standing are allowed to opt out of smart meter installation upon request and at no expense. These customers receive an information packet explaining the benefits of AMI that they would forego by opting out. The customer is required to complete and return forms confirming their acknowledgement that opting out at no expense is an interim solution until the Company has an opt-out program approved by the Commission. See my Schedule 4 for details on the information packet provided when a customer requests to opt out of smart meter installation.

Q. How many customers have opted out of smart meter installation during the initial deployment of AMI?

A. As of June 30, 2019, a total of 694 customers, or 0.16% of our current smart meter population, have chosen to opt out of having a smart meter. However, opt out to date has occurred at no cost to the customer, so the Company expects the percentage of smart meter opt-out customers to decline once fees are imposed.

Q. Please describe the opt-out policy that the Company is proposing going forward.

A. Under the Company's proposed opt-out policy, residential customers taking basic service on Rate Schedule 1 with accounts in good standing will be eligible to opt out of smart meter installation upon request. The Company proposes to impose a one-time initial fee of $84.53 and an ongoing monthly fee of $29.20. These fees are intended to be revenue neutral, meaning that the Company intends to only recover the incremental costs of a customer opting out of smart meter installation. My Schedule 5 provides a draft of the proposed policy, including fees. My Schedule 6 provides a detailed breakdown of estimated up front and ongoing costs associated with customers opting out of smart meter installation. My Schedule 7 provides the proposed update to the Company's Terms and Conditions in clean and redline formats for which the Company seeks approval to implement these proposed fees. Finally, my Schedule 8 provides charts comparing the proposed fees with those imposed by other utilities for smart meter opt out.

Q. Why is the opt-out policy limited to certain residential customers?

A. Customers receiving electric service on any time-varying or demand rate and customers who generate electricity are ineligible to opt out of smart meter installation because detailed energy usage data is required to bill these customers. Allowing these types of customers to opt out of smart meter installation would require maintenance of legacy systems or significant enhancements to existing systems, which the Company has determined to be cost prohibitive.

Additionally, for customers who generate electricity, allowing these customers to opt out of smart meter installation would preclude the Company from monitoring voltage and other characteristics of electrical service at that endpoint—eliminating the end-of-line sensor benefit of smart meters.

Q. What will happen to existing opt-out customers?

A. Once approved, the Company proposes to send all current interim opt-out customers a letter informing them of the opt-out policy and associated fees. These customers will have the option to opt in to AMI at no charge, or they will be transitioned to the approved opt-out program where ongoing fees will be applied to their account from a specified date going forward. The one-time initial fee will not be billed to these interim opt-out customers because the costs have already been recovered through base rates.

II. ELECTRIC VEHICLES

Q. Mr. Frost, what is the status of the electric vehicle ("EV") market today?

A. EVs are continuing to gain market share, largely due to advancements in battery technology, additional EV model availability, declining costs, and benefits provided to customers and the environment. According to a recent Edison Electric Institute Report,[1] the number of EVs on the road in the United States is projected to reach 18.7 million in 2030, which is up from approximately 1 million EVs on the road at the end of 2018. This projection is about 7% of the 259 million cars and light trucks expected to be on U.S. roads in 2030.

In Virginia, as of December 31, 2018, there were approximately 16,500 electric vehicles registered, which is 63% growth since December 31, 2017. Of the 16,500 EVs in Virginia, approximately 11,110 were registered in the Company's service territory. The Company worked with Navigant Consulting, Inc. ("Navigant") to forecast EV adoption in the Company's service territory. Navigant's forecast shows that adoption is expected to increase in the years to come, with about 169,000 EVs projected to be in the Company's Virginia service territory in 2030. See my Schedule 9 for the full adoption forecast.

[1] See *http*://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20 Report_Nov2018.pdf.

Q. **Please provide an overview of the Company's overall strategy to meet this growing demand for electric transportation.**

A. The Company has worked diligently with its customers, stakeholders, and peers, as well as internal and external experts, to develop a comprehensive electric transportation strategy. The strategy includes internal initiatives focused on the Company's own activities and external initiatives designed to ensure grid reliability and to be a trusted resource for customers as they transition to electric transportation. Internally, the electric transportation strategy includes offering workplace charging to employees and incorporating more EVs into the Company's fleet. Externally, the strategy includes developing rate structures and DSM programs that support off-peak EV charging, supporting the development of smart charging infrastructure, and educating customers on electric transportation.

Q. **What portion of this overall electric transportation strategy is the Company seeking approval of in this proceeding?**

A. As part of the GT Plan, the Company is seeking approval of incentives for customers to adopt smart charging infrastructure. The Company is also proposing to own charging infrastructure at certain strategic locations. We will refer to these initiatives as the "Smart Charging Infrastructure Pilot Program."

Q. **Before discussing the Smart Charging Infrastructure Pilot Program, please provide some additional details on other aspects of the Company's electric transportation strategy. What are some examples of the internal EV-related initiatives?**

A. The Company believes that the electrification of transportation provides a number of benefits, and plans to lead by example. The Company has worked collaboratively with its corporate parent, Dominion Energy, Inc. ("Dominion Energy"), to enable many of its internal EV-related initiatives. For example, in May 2019, the Company began operating an all-electric shuttle between its Richmond-based offices. The Company will continue to add additional electric vehicles to its fleet with a goal of having 25% of its light duty fleet converted to electric or plug-in hybrid electric by 2025. As another example, Dominion Energy is installing workplace charging stations at a number of offices. These initiatives support electric transportation options for employees and will help the Company gain installation and operating experience—experience that it can use to help its customers who have similar initiatives.

Q. You also mentioned external initiatives to develop rate structures and DSM programs that support smart EV use. Please elaborate.

A. The Company is developing new, time varying rate structures to allow customers, including EV drivers, to better manage their energy usage. Company Witness Morgan addresses the status of those efforts and the Company's plan to file an experimental, voluntary time varying rate.

The Company is also evaluating DSM programs designed to encourage efficient charging of electric vehicles and shifting of electric vehicle charging load to off-peak periods. The Company solicited market input for EV-related DSM program designs in its most recent DSM RFP. The Company is currently evaluating the results from the DSM RFP in advance of its next DSM filing.

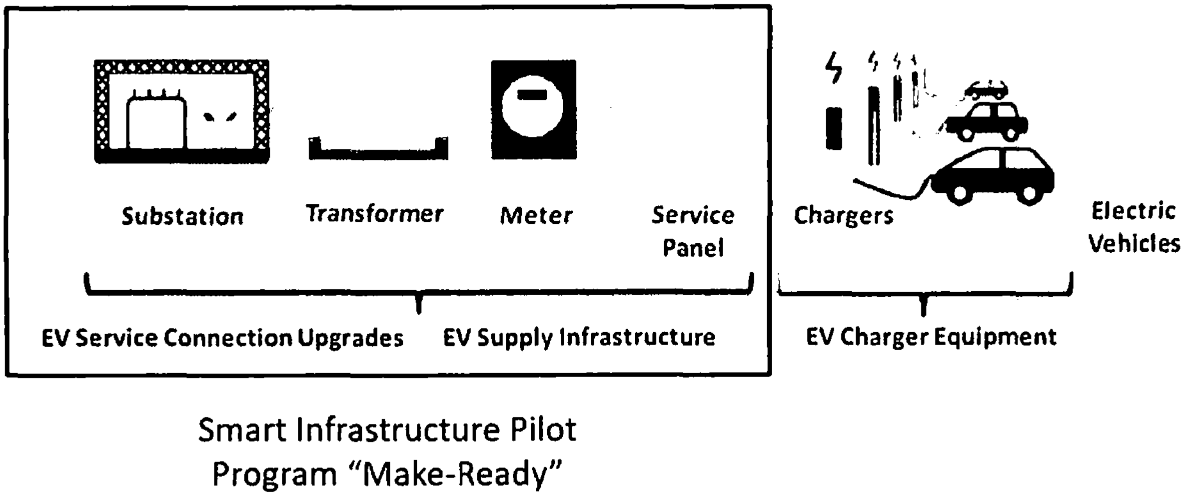
Q. Are there any other external initiatives aside from the Smart Charging Infrastructure Pilot Program that you would like to highlight?

A. Yes, the Company recently launched three other EV-related initiatives that I would like to mention. First, earlier this year, the Company launched an innovative online electric vehicle educational tool at www.dominionenergy.com/EV, which consists of a savings calculator, information on carbon reduction, a charger finder, and more. The Company launched this website to respond to customer questions and to further efforts in gaining customers' trust in the Company as an expert for electric transportation. Second, on August 29, 2019, the Company announced an innovative electric school bus initiative to replace diesel school buses with electric school buses, and then leverage the batteries using vehicle-to-grid technology. Third, the Company is evaluating a potential project to study battery storage paired with direct current fast charging infrastructure, which should provide feedback on the capabilities of the technology.

Q. Turning to the Smart Charging Infrastructure Pilot Program, please explain the proposed program.

A. The proposed Smart Charging Infrastructure Pilot Program aims to provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional investments, pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid. The Pilot Program will consist of (i) rebates for the infrastructure and upgrades, if necessary, at EV charging sites, often referred to as the "make-ready," and (ii) rebates for the smart charging equipment that enables managed charging. Figure 3 provides a diagram of these two components of EV infrastructure.

Figure 3: EV Infrastructure Diagram



Source: Edison Foundation, Plug-in Electric Vehicle Sales Forecast Through 2030 and the Charging Infrastructure Required, Figure 7

The Pilot Program will also include Company-owned charging infrastructure at strategic locations.

Q. **Does Smart Charging Infrastructure Pilot Program meet the definition of an electric distribution grid transformation project under Va. Code § 56-576?**

A. Yes, the Pilot Program includes investment in "electrical facilities and infrastructure necessary to support electric vehicle charging systems."

Q. **Are there other policies that support the Company's strategy, including the Smart Charging Infrastructure Pilot Program?**

A. Yes. The Virginia Energy Plan encourages the shift to alternative fuel transportation including electric vehicles. The Virginia Energy Plan also mentions the benefits of managed charging. The Company's Smart Charging Infrastructure Pilot Program also supports the Commonwealth's participation in the Transportation Climate Initiative by encouraging low-to-no emission vehicles in furtherance of reducing pollution from the transportation sector.

Q. As you did in the AMI section above, can you please address the Commission's four requirements the 2018 IRP Final Order as they relate to the Smart Charging Infrastructure Pilot Program?

A. Yes, I will discuss each of these items in turn. I will also discuss the proposed deployment plan developed based on the identified need, as well as the Company's plan for customer education related to the Pilot Program.

A. Existing System, Need, and Proposed Deployment Plan

Q. Please explain how EVs are typically charged.

A. Charging an EV requires plugging in to a charger that is connected to the electric grid. There are three major categories of chargers that are distinguishable by the amount of power the charger can provide, which results in different speeds of charging. Level 1 refers to use of a standard 120-volt ("V") outlet, which charges three to five miles of range per hour. Level 1 charging is ideal for overnight charging for EV owners that travel about 30 miles or fewer per day. Level 2 chargers require a higher voltage at 240V, which charges 10 to 20 miles of range per hour. Level 2 charging is ideal for workplaces, multi-family dwellings, and locations with the potential for more electric vehicles than chargers. Finally, Level 3—also known as direct current fast charging ("DC Fast Charge" or "DCFC")—can charge an EV battery to approximately 80% of capacity in 20 to 30 minutes. DCFC requires three-phase electric service and significant capacity. It is ideal for public locations to support travel over long distances.

Q. What is the current status of charging infrastructure in Virginia?

A. As of August 15, 2019, there were approximately 595 Level 2 and DCFC charging stations in Virginia available for public use according to the Alternative Fuels Data Center. The Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of the charging stations installed in Virginia, including several sites with connected load of over one megawatt.

While the number of charging stations may seem significant, not all of these stations are available to all EV drivers. For example, many of the DCFC stations are Tesla Superchargers, which are limited to Tesla drivers. Others are installed at dealerships and are only available during business hours. There are also concerns about redundancy; many charging stations sites only have one station, meaning if the station is in use or out of service, an EV driver must wait or attempt to find another charging site. Lastly, most of the non-Tesla DCFC stations have a charging capacity of only 50 kilowatts ("kW"), which is faster than Level 2 charging, but still can require more than one hour to charge an EV battery to 80%. Newer DCFC technology is often 100 kW or higher, which can charge an EV battery much faster than 50 kW technology.

Q. Will this charging infrastructure support the projected level of adoption of EVs in the Commonwealth?

A. No. Industry sources attempt to project the level of charging infrastructure needed to support specific levels of adoption. To support 169,000 EVs forecasted to be in Virginia in 2030, the Department of Energy's EVI-Pro Lite tool[2] estimates the following infrastructure is needed:

- 3,778 workplace charging Level 2 plugs;
- 2,614 public Level 2 charging plugs; and
- 414 public DCFC charging plugs.

My Schedule 10, page 1 of 2, shows the results from the Department of Energy's EVI-Pro Lite tool.

Q. What are the drivers of the Smart Charging Infrastructure Pilot Program?

A. Though the level of adoption varies by source, industry experts agree that EV adoption will continue to increase, and with that adoption comes increased demand for electricity. The Company recognizes the opportunity to manage this increased demand to minimize impacts on the distribution grid and increase overall grid utilization.

Q. What is managed charging and why is it important?

A. Managed charging—also called intelligent or smart charging—allows a utility or third-party to remotely control vehicle charging by turning it up, down, or off to better correspond to the needs of the grid, much like traditional demand response programs. Managed charging is important because without awareness of the additional load resulting from EV charging and the ability to manage it, the Company loses the opportunity to reduce the impacts on the distribution grid.

As shown in Schedule 9, approximately 169,000 EVs are forecasted in the Company's Virginia service territory, requiring 558 gigawatt-hours ("GWh") of electricity annually

[2] *See* https://afdc.energy.gov/evi-pro-lite.

with a demand of 187 megawatts ("MW"). Prudently integrating and managing EV charging load on the grid is foundational to the Company's EV strategy, and vital to the Company's larger grid transformation objectives. The Company is not alone in this goal. According to the Smart Electric Power Alliance, as of May 2019, there were 38 utility-run managed charging pilots or programs for residential customers, multi-family customers, workplaces, fleets, public charging, and transit.

Q. How many rebates does the Company propose to offer through the Smart Charging Infrastructure Pilot Program, and to whom?

A. The Pilot Program will offer rebates to multi-family sites, workplace sites, public DCFC sites, and to transit agencies installing infrastructure for electric buses. The table below provides a summary of the segments, incentive amounts, and number of incentives.

Table 3: Phase IB Rebates

Segment	Rebate Amount	Number of Charging Stations During Phase IB
Multi-family	• Up to $4,071 for each dual port Level 2 networked charging station • Up to $11,140 for make-ready for each station	Up to 25 charging stations
Workplace	• Up to $2,714 for each dual port Level 2 networked charging station, • Up to $11,140 for make-ready for each stations	Up to 400 charging stations

Segment	Rebate Amount	Number of Charging Stations During Phase IB
DCFC	• Up to $36,720 for each dual port networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 30 charging stations; each customer must install at least two charging stations per site that can charge all EV types; each customer is limited to four rebates
Transit	• Up to $53,451 for each networked DCFC charging station • Up to $73,500 for make-ready for each station	Up to 60 charging stations; each customer is limited to a maximum of six rebates

To be eligible for a rebate, the site host must agree to provide charging data to the Company. The data includes, but is not limited to, time and duration of charging sessions, energy consumed, and peak demand during the charging sessions. The site host is responsible for the procurement, installation, and ownership of the EV charging station(s). The rebate amounts for the make-ready are designed to offset the cost of the electrical infrastructure and upgrades needed to install the smart charging infrastructure. The rebate amounts for the charging stations are designed to help offset the incremental cost of installing a smart charging station instead of a charging station without the ability to collect charging data and participate in managed charging.

Q. **You stated that the Company will also own charging infrastructure at strategic locations as part of the Smart Charging Infrastructure Pilot Program. Please explain.**

A. Yes. The Company is proposing to own up to four charging stations during Phase IB as part of its ongoing strategy to support electrification in the rideshare market segment. The rideshare segment refers to car services that allow a rider to use a smartphone app to arrange a ride in a privately owned or leased vehicle for a fee. Including the rideshare market segment in the Smart Charging Infrastructure Pilot Program is important for several reasons. The number of vehicle miles traveled in the rideshare market is growing exponentially. Similar to other segments mentioned above, the Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from rideshare EV drivers and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program. The Company is proposing to own four charging stations sited to strategically enable additional electric vehicles to participate in rideshare platforms, and to study the charging behavior and impacts to the distribution system resulting from rideshare EV drivers concentrated in a certain area. The Company will install and own the charging stations; procurement will be through an RFP process. The Company is engaged in ongoing discussions with the rideshare industry to identify location(s) for this initiative. Locations will be in the Company's Virginia service territory. If approved, the Company will solicit site hosts in the strategically sited areas, ensuring the stations are accessible to both rideshare drivers and the public. Site hosts at the identified locations will be responsible for electricity bills, and any fees collected from drivers for the use of the charging stations will be provided to the site hosts. The Company will not retain any fees collected from drivers for the use of the charging stations.

Q. How did the Company determine what segments to target?

A. The Company determined what segments to target based on its prior experience and identified areas for growth.

In 2011, the Company launched its Electric Vehicle Pricing Plans Pilot Program to learn about its residential customers' EV charging behaviors and to study the impacts of EV charging on the grid; the Commission approved that Pricing Pilot Program in Case No. PUE-2011-00014. By the conclusion of the Pricing Pilot Program in 2018, the Company had developed a general understanding of current residential charging behavior and potential impacts to the distribution system. Accordingly, the Company is not proposing to further pilot a program for residential single-family customers. Instead, the Company is evaluating managed charging programs for single-family residential customers as part of its future DSM filings.

Since the conclusion of the Pricing Pilot Program, the EV market in Virginia has continued to grow and charging technologies and behaviors have continued to evolve. Interest in EVs has expanded from largely single-family residential customers to customers in many other segments with different charging behaviors. The Company seeks to lay the groundwork to offer pilot programs for several of these segments as part of this proceeding.

Industry experts agree that the majority of EV charging happens at home. Many multi-family residential customers, such as those in apartment complexes or condominiums, are not able to install EV charging at their residence. Instead, EV charging infrastructure would need to be installed in common areas. These customers were not part of the Pricing Pilot Program; thus, the Company seeks to incent smart charging infrastructure at multi-family locations to understand charging behavior and impacts to the distribution system as adoption increases in this segment.

The second most common location for EV charging is at work. Workplace charging allows EV drivers to increase their electric driving range each day, reduces range anxiety, and provides charging options for drivers who do not have access to home charging. The Company is not aware of widespread proliferation of workplace charging stations installed in Virginia and seeks to incent smart charging infrastructure to gather the data necessary to understand workplace charging behaviors and the impacts to the distribution system for this segment.

As stated earlier in my testimony, the Company has worked with charging station companies including Tesla Motors, Electrify America, and EVgo Services to interconnect the majority of DCFC stations installed in Virginia. These charging stations are not individually metered, so the Company seeks to incent smart charging infrastructure to obtain the data necessary to understand charging behavior and impacts to the distribution system resulting from charging at DCFC stations.

Q. Please continue.

A. In addition to charging infrastructure for passenger EVs, the Smart Charging Infrastructure Pilot Program includes incentives for smart charging infrastructure for transit agencies and universities who are electrifying their bus fleets. Similar to passenger EVs, electric transit buses are cheaper to fuel and maintain than traditional diesel buses. Electric buses provide significant environmental benefits over diesel buses in the form of reduced greenhouse gas emissions and reduced transportation noise. There has also been an influx of grant funding for electric transit buses, including in Virginia. For these reasons, the Company believes electric transit bus adoption will increase significantly over the next few years. Indeed, over the last 12 months, the Company has received seven inquiries from transit agencies and universities with bus fleets regarding electric buses. The DCFC infrastructure for transit buses can range from 60 kW to 500 kW per charger. The Company does not have the data necessary to understand charging behavior and impacts to the distribution system resulting from charging electric transit buses, and seeks to obtain this data through the Smart Charging Infrastructure Pilot Program.

The Company chose to include the rideshare segment to understand charging behavior and impacts to the distribution system resulting from vehicles that have high daily vehicle miles traveled in a concentrated area. The Company also believes that including both the transit and rideshare segments in its Smart Charging Infrastructure Pilot Program will lead to more equitable future pilots, programs, or rate designs to support EV adoption while minimizing the impact of EV charging on the distribution grid.

In summary, the Company believes collecting the data necessary to understand the charging behaviors of the segments above and the potential impacts to the distribution grid will benefit all customers because it will position the Company to design programs and rate designs to encourage managed charging.

Q. Does the Company's EV strategy include options for vulnerable customers, such as low income, elderly, and disabled individuals?

A. Yes. Electrifying transit buses will extend the benefits of electric transportation to customers that may not be physically able to drive a vehicle of their own, or that may not be financially able to purchase a vehicle. The Company's incentives for multi-family communities can provide charging infrastructure for customers in affordable housing. Additionally, the Company is committed to supporting electric rideshare vehicles; many such rides start or end in low income areas, with a Richmond Times Dispatch article reporting that 58% of local Lyft rides start or end in low-income areas.[3] Encouraging EVs in the rideshare segment will help ensure the benefits of electric transportation, such as air quality improvement, are seen in low income areas, which are often areas that are impacted with disproportionally higher emissions.

Q. Why is the Company referring to this initiative as a Pilot Program?

A. The Company is referring to this initiative as a Pilot Program because it will incent installation of the required infrastructure and collect the baseline data required to be able to design managed charging programs and other customer offerings that will support EV adoption while minimizing EV charging impacts to the distribution grid.

Q. What is the deployment schedule for the Smart Charging Infrastructure Pilot Program?

A. During the fourth quarter of 2019, the Company will issue an RFP for turn-key implementation services for the Pilot Program, including enrollment, communications, rebate processing, and evaluation. The Company will also issue an RFP for the Company-owned charging infrastructure in 2019.

If approved, the Company intends to implement the Smart Charging Infrastructure Pilot Program within 60 days of approval. The Company plans collect and evaluate data obtained as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021. In late 2021, the Company anticipates requesting approval of managed charging

[3] *See* https://www.richmond.com/opinion/their-opinion/cabell-rosanelli-column-continue-richmond-s-transportation-evolution/article_57d01f4b-d097-512a-8936-aab3f5c64c39.html. *See also* https://www.forbes.com/sites/korihale/2019/04/02/lyfts-minority-drivers-level-up-in-26-billion-ipo/#23c684882983 (reporting that 44% of Lyft rides start or end in low income areas).

pilots, programs, or rate designs. Importantly, without the data collected as part of the Smart Charging Infrastructure Pilot Program during 2020 and 2021, the Company would not be able to design customer offerings specific to the charging behavior of its customers.

B. Cost Estimates

Q. What is the Company's projected investment for the Smart Charging Infrastructure Pilot Program during Phase IB?

A. Table 4 shows the Company's anticipated capital and O&M investments for the deployment of AMI during Phase IB. Table 4 is an excerpt from my Schedule 1.

Table 4: Phase IB Estimated Smart Charging Infrastructure Pilot Program Capital and O&M Investment (in millions)

2019		2020		2021		Total 3 Years	
Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M
$0	$0.4	$1.5	$5.3	$2.4	$11.4	$3.9	$17.1

Q. What is the Company's total projected investment for the Smart Charging Infrastructure Pilot Program?

A. As shown in Schedule 1, the Company anticipates an estimated $7.3 million in capital investment and $42.9 million in O&M investment over the 10-year GT Plan period.

Q. How did the Company develop these estimates and ensure they are reasonable?

A. The Company began with the EV adoption forecast for its Virginia service territory developed by Navigant, attached as my Schedule 9. Next, the Company used the Department of Energy's EVI-Pro Lite tool to estimate the charging infrastructure required to support the number of EVs in the forecast in 2030, as shown in my Schedule 10. Assuming an equal number of required charging stations will be installed per year between 2020 and 2030, the Company calculated the number of charging stations that is estimated to be installed in 2020 and 2021. This served as the basis for the number of rebates proposed in the Smart Charging Infrastructure Pilot Program. The Company believes the number of rebates is reasonable for a two-year pilot program because the number of rebates is based on the infrastructure that will likely be installed during Phase IB.

The Company gathered cost information from various sources to determine the incremental cost of the smart charging stations and the costs for construction and installation. Dominion Energy Services, Inc., issued an RFP for workplace charging stations in March 2019. The Company also solicited pricing from bidders for other types of charging stations, including DCFC stations. Filing Schedule Frost, Attachment C provides a summary of the RFP. The Company used the responses to the RFP as indicative pricing and this pricing served as the basis for the rebate amounts for the charging stations. The Company requested input from several charging station companies regarding installation costs and used this input, coupled with its experience interconnecting charging stations, as indicative pricing for make-ready. The rebate quantities and incentive amounts for the transit segment are based on input from transit agencies, transit bus manufacturers, and the Virginia Statewide Contract for electric transit buses, which was established by the Virginia Department of General Services earlier this year.[4] The costs associated with owning infrastructure were developed based on discussions with charging station equipment manufacturers.

The Company used its experience implementing other pilot programs, such as the Electric Vehicle Pricing Pilot Program, to estimate its administrative activities and costs.

C. Benefits of Smart Charging Infrastructure Pilot Program

Q. What are the benefits of the Smart Charging Infrastructure Pilot Program?

A. The benefits of the Smart Charging Infrastructure Pilot Program are both quantitative and qualitative, including energy and demand savings; fuel and maintenance savings for EV drivers; and reduced greenhouse gas emissions. As I noted above, Company Witness Hulsebosch supports the benefits of the Pilot Program.

D. Alternatives Considered

Q. What alternatives to the Smart Charging Infrastructure Pilot Program did the Company consider?

A. The Company considered a "do nothing" alternative. As shown in my Schedule 9, the approximately 169,000 forecasted in the Company's Virginia service territory in 2030 will require 558 GWh of electricity annually with a demand of 187 MW. As new EV charging load comes on to the grid, grid upgrades will likely be necessary. However, if new EV charging load comes on to the grid at times of peak demand, it can result in higher costs to absorb that load. If the Company were to "do nothing" in terms of managing new EV charging load, it could result in higher costs for the Company and its

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[4] *See* https://logi.epro.cgipdc.com/External/rdPage.aspx?rdReport=Public.Reports.Report9008_Data&lnk From=New.

customers, such as the need for additional distribution upgrades or the need for more fast ramping peaker plants.

In order to fully and prudently support EV adoption, the Company believes that investments in managed EV charging are needed today—in the earlier years of EV adoption to allow the Company the necessary time to implement supporting technologies and infrastructure, and to adapt workforce skills to support them. This includes deploying and learning how to validate methods and processes for managed charging in a diversity of customer scenarios. As a result, we believe it is necessary to lay the groundwork for managed charging today to enable expanded EV adoption in a way that sustains grid reliability and safety.

Q. Did the Company consider any other alternatives?

A. The Company developed the Pilot Program based on the forecasted approximately 169,000 EVs in the Company's service territory in 2030, but also evaluated the low and high forecast scenarios provided by Navigant.

The low scenario provided by Navigant would have a smaller impact on the Company's distribution system; however, the risk of doing nothing still remains. If the Company assumes the low scenario and actual adoption of EVs is higher, and if non-networked, uncontrollable charging stations without the ability to provide data or participate in managed charging are installed, the Company will not have awareness of the resulting EV charging load or the ability to manage it. The Company believes it would be unlikely for customers to remove their non-networked, uncontrollable charging stations shortly after installing them to install networked controllable charging stations to take advantage of managed charging programs. The Company determined the high scenario was not an appropriate assumption for a pilot program as proposed in Phase IB.

E. Customer Education

Q. Please explain the education and communications that will accompany the Smart Charging Infrastructure Pilot Program.

A. The education and communications that will accompany the Smart Charging Infrastructure Pilot Program consist of communications to solicit customer enrollment and ongoing communications with participants. Customer enrollment solicitation will include web content, social media, and other outreach. Ongoing communications with participants will include continued education on managed charging, surveys to obtain customer feedback, and customer service associated with participation in the Pilot Program. For additional discussion on customer education, see Section VI.A.7 of the Plan Document.

III. CONCLUSION

Q. Mr. Frost, please summarize your testimony.

A. My testimony covered two components of the Company's Grid Transformation Plan, the full deployment of AMI and the Smart Charging Infrastructure Pilot Program.

Starting first with the Smart Charging Infrastructure Pilot Program, the Company proposes to offer rebates to incent the infrastructure necessary for managed charging, also referred to as "smart" charging. In addition, the Pilot Program includes Company-owned charging at strategic locations. The information gained from the proposed Pilot Program will provide the Company with the data and tools necessary to understand and manage future EV charging load in furtherance of additional pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid.

Turning to AMI, the Company proposes to fully deploy smart meters AMI across its Virginia service territory. Through AMI, the Company can remotely read smart meters and send commands, inquiries, and upgrades to individual smart meters, minimizing the need for field visits. From a foundational perspective, the over-arching benefit of full AMI deployment cannot be overstated. Nearly every investment within the Grid Transformation Plan relies directly on or is enabled by full AMI deployment. Benefits from full deployment of AMI include operational efficiencies and increased information and control of the electric grid for the Company; customer benefits in savings, convenience, information, and reduced energy consumption; and additional benefits in reduced greenhouse gases.

Q. **Does this conclude your pre-filed direct testimony?**

A. Yes, it does.

Appendix A

BACKGROUND AND QUALIFICATIONS
OF
NATHAN J. FROST

Nathan J. Frost graduated from James Madison University with a Bachelor of Business Administration in Finance. He joined Dominion Energy in 2005 and has held numerous positions in the areas of Enterprise Risk Management, Producer Services, Investor Relations, and Power Delivery. Mr. Frost was most recently Manager – New Technology and Renewable Programs for Dominion Energy Virginia, and assumed his current position as Director – New Technology and Energy Conservation for Dominion Energy Virginia in January 2019. In this position, Mr. Frost is responsible for delivering demand side management and advanced metering solutions for the Company. In addition, he is responsible for developing renewable energy programs and integrating new technologies such as solar distributed generation and electric vehicles with Dominion Energy Virginia's regulated service territory.

Mr. Frost has previously submitted testimony before the State Corporation Commission of Virginia.

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of AMI Capital Costs**					
2						
3	Meter Deployment Labor Costs	$ 4,817,192	$ 14,746,306	$ 20,868,194	$ 40,431,692	$ 93,908,198
4	Meter & Meter Hardware Costs	$ 7,648,555	$ 50,682,244	$ 70,583,342	$ 128,914,140	$ 261,133,576
5	Network Materials & Installation Costs	$ 826,398	$ 1,446,515	$ 2,953,638	$ 5,226,551	$ 11,370,152
6	Licensing & Communications	$ 262,448	$ 1,690,168	$ 2,432,637	$ 4,385,254	$ 9,451,670
7	Capability Development/Enhancement	$ 1,299,671	$ 3,292,951	$ 3,445,551	$ 8,038,173	$ 18,567,744
8						
9	Total AMI Capital Costs	$ 14,854,264	$ 71,858,184	$ 100,283,362	$ 186,995,810	$ 394,431,340
10						
11						
12	**Summary of AMI O&M Costs**					
13						
14	Internal Labor, Vehicle, & Travel	$ 609,608	$ 968,088	$ 900,958	$ 2,478,654	$ 5,292,594
15	Hardware/Software Maintenance, Communications, & Call Center	$ 1,313,783	$ 2,056,922	$ 3,721,143	$ 7,091,848	$ 48,603,942
16						
17	Total AMI O&M Costs	$ 1,923,391	$ 3,025,011	$ 4,622,101	$ 9,570,502	$ 53,896,535
18						

Key Inputs	
Depreciable life	11.4yrs
3yr Total AMI Meter Deployment Count (2019-2021)	985,639
6yr Total AMI Meter Deployment Count (2019-2024)	2,116,548

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Stakeholder Engagement & Customer Education Capital Costs**					
2						
3						
4	Total Stakeholder Engagement & Customer Education Capital Costs	$ -	$ -	$ -	$ -	$ -
5						
6						
7	**Summary of Stakeholder Engagement & Customer Education O&M Costs**					
8						
9	Collateral & Events	$ 40,000	$ 1,335,500	$ 1,558,860	$ 2,934,360	$ 9,433,106
10	Internal Dominion Labor	$ -	$ 100,000	$ 200,000	$ 300,000	$ 1,700,000
11						
12	Total Stakeholder Engagement & Customer Education O&M Costs	$ 40,000	$ 1,435,500	$ 1,758,860	$ 3,234,360	$ 11,133,106
13						

Company Exhibit No. __1
Witness: NJF
Schedule 1
Page 3 of 3

Line No.	Description	2019 Yr 1	2020 Yr 2	2021 Yr 3	3 Yr Total Sum (C)-(E)	10 Yr Total Sum (C)-(L)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Summary of Transportation Electrification Capital Costs**					
2						
3	Rideshare Charging Station Make Ready and Equipment ($)	$ -	$ 699,700	$ -	$ 699,700	$ 2,798,800
4	Transit Bus Charging Station Make ready ($)	$ -	$ 420,000	$ 1,680,000	$ 2,100,000	$ 2,100,000
5	Public DC Fast Charge Station Make Ready ($)	$ -	$ 350,000	$ 700,000	$ 1,050,000	$ 2,450,000
6						
7	Total Transportation Electrification Capital Costs	$ -	$ 1,469,700	$ 2,380,000	$ 3,849,700	$ 7,348,800
8						
9						
10	**Summary of Transportation Electrification O&M Costs**					
11						
12	**Program Management ($)**	$ 393,500	$ 1,167,842	$ 1,329,881	$ 2,891,223	$ 17,163,695
13	**Single-Family Residential Program Costs**					
14	Single-Family Residential Charger - Equipment Rebate Expense ($)	$ -	$ 116,375	$ 148,375	$ 264,750	$ 1,329,375
15	Single-Family Residential Charging Program O&M Expense ($)	$ -	$ 102,792	$ 162,504	$ 265,296	$ 6,527,793
16	**Multi-Family Residential Program Costs**					
17	Multi-Family Residential Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 152,110	$ 228,165	$ 380,275	$ 1,521,100
18	**C&I Program Costs**					
19	Workplace Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,939,560	$ 3,602,040	$ 5,541,600	$ 5,541,600
20	**Public Transit Program Costs**					
21	Transit Bus Charging Station - Make-Ready/Equipment Rebate Expense ($)	$ -	$ 1,103,406	$ 4,413,624	$ 5,517,030	$ 5,517,030
22	**Public DC Fast Charging Program Costs**					
23	Public DC Fast Charge Station - Make-Ready Rebate Expense ($)	$ -	$ 752,200	$ 1,504,400	$ 2,256,600	$ 5,265,400
24						
25	Total Transportation Electrification O&M Costs	$ 393,500	$ 5,334,285	$ 11,388,989	$ 17,116,774	$ 42,865,994
26						

Key Inputs	
Asset Life	11 yrs
Single-Family Residential Chargers (cumulative in Year 10)	44,268
Steady State Multi-Family Charging Stations	100
Steady State Workplace Charging Stations	400
Steady State Transit Bus Charging Stations	60
Steady-State DC Fast Charging Stations	70
Steady-State Rideshare Charging Stations	16

19050003

Just like our linemen, our new Smart Meters will work hard for you.

By upgrading to new, advanced metering technologies, we're investing in our infrastructure and in our customers.

Dominion Energy

Smart Meters: our newest metering technology for managing energy.

You're due for an upgrade. Soon, Dominion will be exchanging existing meters in your area for new Smart Meters. Why? To continue providing you with better service—like more reliable delivery of energy, better power-outage detection, faster problem resolution and remote meter reading. Smart meters also allow you to view your daily energy usage and participate in pricing plans which help you manage energy and costs.

The meter upgrade will require only a momentary power interruption; no need for you to make an appointment or be present during the exchange.

For more information, including how to view your daily energy usage, please visit DominionEnergy.com/smartmeter

The meter upgrade will occur at:

Dominion Energy®

P.O. Box 26666
Richmond, VA 23261

190950003

Dominion Energy

DOES NOT
PRINT-DIE
INDICATOR

By upgrading to new, advanced metering technologies, we're investing in our infrastructure and in our customers.

Date ______________________________

☐ **A utility service representative upgraded the electric meter today.** If you have any questions or concerns related to the meter exchange, please call:

866-566-6436 | 8 AM to 5 PM, Monday to Friday

☐ A utility service representative stopped by today to upgrade the electric meter. However, **the meter could not be exchanged due to:**

____

____

To discuss the issue and reschedule the meter upgrade, please call:

844-562-9472 | 8 AM to 5 PM, Monday to Friday

DominionEnergy.com/smartmeter

DOES NOT
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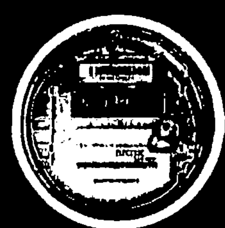
INDICATOR

THE EVOLUTION OF METER TECHNOLOGY

2010s

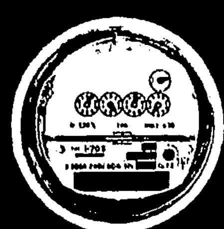
AMI
Advanced Meter Infrastructure

1990s



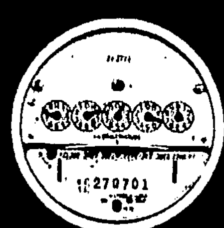
AMR
Automated Meter Reading

1980s



OMR
Off-Site Meter Reading

1950s



Simple Spinning Dial

<Premise Address>

<Account Number>

<Mailing Address>

<Date>

Dear Valued Customer,

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters in your area.

This letter is in response to your inquiry for more information about the **Interim Non-Communicating Meter Option (Residential "Opt-Out")**. If you decide to opt-out, the meter at your location will be replaced with non-communicating equipment. The non-communicating meter does not have any data storage features or two way communication functions enabled. As a result, it will be necessary for a meter reader to obtain a visual meter reading monthly.

Smart meters allow innovative features to:

- give you more control over how you use energy by providing you with information about energy usage;
- notify Dominion Energy when your power is out and back on for efficient restoration; and
- offer flexible, alternative pricing structures based on usage data.

Please find a summary comparing smart meters (communicating) to the opt-out program meters (non-communicating).

<u>Comparison of Meter Features</u>

	Standard Smart Meters (Communicating)	Opt-Out Program Meters (Non-Communicating)
Remote Outage Detection	**Yes**	**No**
Remote Service Connection	**Yes**	**No**
Customer Pricing Plan Options	**Yes**	**No**

Currently, Dominion Energy does not charge any special installation or usage fees to customers who choose the Interim Non-Communicating Meter Option; however, since manual monthly meter readings are required for these non-communicating meters, Dominion Energy may propose recovering expenses in the future. Such fees are subject to approval by the State Corporation Commission of Virginia (SCC) and, if approved, Dominion Energy will inform all participants of the Interim Non-Communicating Meter Option.

Hopefully, you will agree upgrading to a smart meter offers many benefits and is the best option for you. Should you wish to opt-out, please review the enclosed Interim Non-Communicating Meter Option requirements and **<u>sign and return the Enrollment Form</u>** as soon as possible.

A meter exchange will be necessary regardless of which meter you choose. Service will be momentarily interrupted during the meter exchange. Customers do not need to be present for the meter exchange, provided adequate access to the meter is available. Please visit our website at DominionEnergy.com/smartmeter or call 1-866-566-6436 for additional information.

Sincerely,

Smart Meter Team
Dominion Energy

Enclosures:
Interim Non-Communicating Meter Option Requirements
Enrollment Form

By receiving electric service from Dominion Energy, customers are subject to the Company's Terms and Conditions for the Provision of Electric Services. Pursuant to Section V of the Terms and Conditions, Dominion Energy owns the meter currently installed at your residence/business and has the right to have unobstructed, safe, and convenient access including but not limited to repair, replace, or exchange the meter. Additionally, as stated in Section XV, Dominion Energy has the right to access customer premises at all reasonable times for the purpose of reading meters, removing its property, and for other proper purposes such as the meter exchange. For an electronic version of Dominion Energy's Terms and Conditions please visit our website, DominionEnergy.com/terms.

Interim Non-Communicating Meter Option
REQUIREMENTS

The following requirements apply to the Interim Non-Communicating Meter (Residential Opt-Out) Option. The Non-Communicating meters are Advanced Metering Infrastructure ("AMI") or Smart Meters with both the two-way communications and data storage features disabled; the only recording features retained are the minimum needed for monthly billing. Because the Non-Communicating Meters' remote communication abilities have been disabled, a Dominion Energy ("Company") representative will manually read the meter.

To participate in this Option, please review these requirements and then sign and return the enclosed enrollment form.

Eligibility Requirements Guidelines and Restrictions

- These Option specific requirements are in addition to the Company's *Terms and Conditions for the Provision of Electric Service* ("Terms and Conditions") currently on file with the State Corporation Commission of Virginia ("Commission"), under which customers receive their Electric Service.

- An Interim Non-Communicating Meter Option Participant (the "Participant") must be a residential customer and can only request the Interim Non-Communicating Meter Option for accounts which they have authority to make account level changes. The Participant must submit an individual enrollment form for each account which enrollment is requested.

- The Participant must already have an AMI meter, or currently scheduled for an AMI meter upgrade.

- Participant must currently receive Electric Service from the Company in accordance with residential Rate Schedule 1 or transfer to Rate Schedule 1 prior to enrolling in the Interim Non-Communicating Meter Option. Non-Communicating Meters are not applicable for customers receiving Electric Service on dynamic-pricing (e.g., Rate Schedule DP-R) or any residential time-of-use rate schedule (e.g., Rate Schedule 1P, 1S, or 1T). In addition, Non-Communicating Meters are not applicable to situations in which the customer generates electricity or additional metering data is required for billing (e.g., Net Metering and Bidirectional Metering, Rate Schedule SP – Solar Purchase (Experimental)).

- The Participant is responsible for providing and maintaining access to the Company for purposes of meter installation, maintenance, and reading, in accordance with Section XV of the Company's Terms and Conditions. The Company has the right of access to the Participant's premises at all reasonable times and must have safe access to the meter.

The Company reserves the right to discontinue this Interim Non-Communicating Meter Option, if such access is not provided and maintained by the Participant.

- The Company has the right to modify these requirements from time to time at its discretion. The most recent version of the requirements is available on the Company's website at DominionEnergy.com/smartmeter.

- The Company plans to propose a charge for the Non-Communicating Meter Option, which will be subject to approval by the Commission. Upon Commission approval, the Company will inform customers who are currently participating in the Interim Non-Communicating Meter Option and will require such customers to enroll in the Commission approved Non-Communicating Meter Option, subject to any Commission approved fee, in order to continue using a Non-Communicating Meter. At that time, the Company will begin assessing any Commission approved fee for customers participating in the Non-Communicating Meter Option.

- Smart Meters help the Company operate its electric distribution infrastructure more efficiently by reducing the amount of excess voltage generated. As a result, customers and the Company may experience savings. By participating in the Non-Communicating Meter Option, the Participant acknowledges that the Company's ability to identify voltage-related concerns, notwithstanding the requirements set forth in Section VII of its Terms and Conditions, may be delayed or compromised.

- Upon receipt and approval of the completed enrollment form, the Company will schedule a meter exchange to coincide with the AMI deployment schedule. In cases where an AMI meter is already installed, the exchange to the Non-Communicating Meter will be completed within three weeks. Service will be momentarily interrupted during the meter exchange process. Customers do not have to be home for the meter exchange as long as adequate access to the existing meter is available.

- Accounts must be in good standing without any pending, recently completed, or active credit activity scheduled on the account.

- Participants may contact the Company to withdraw from the Interim Non-Communicating Meter Option at 1-866-566-6436 between 8:00 a.m. and 5:00 p.m. (Eastern Time) Monday through Friday.

Interim Non-Communicating Meter Option
ENROLLMENT FORM

Customers electing to enroll in the Interim Non-Communicating Meter (Residential Opt-Out) Option are required to complete this enrollment form and return it in the enclosed envelope or by email to ReceivedOpt-OutEnrollmentForms@DominionEnergy.com. Once Dominion Energy has received this signed and completed form, the enrollment will be processed and scheduled in accordance with the Interim Non-Communication Meter Requirements.

Customer Name and Address:

<XXXXX>
<XXXXX>
<XXXXX>

Account Number:

<XXXXXXXXXX>

By signing below, I hereby certify that I have the authority to make account level changes on the account listed above, and that I have fully read and agree to be bound by the requirements of the Interim Non-Communicating Meter Option. The latest requirements can be found at DominionEnergy.com/smartmeter.

PRINTED NAME:

____

SIGNATURE: DATE:

______________________________ ______________

Smart Meter Opt-Out Policy (DRAFT)

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters.

Smart meters enable innovative features to:

- provide the customer with detailed information about their energy usage;
- offer flexible, alternative pricing structures based on detailed energy usage data; and
- notify the Company when a customer's power is out and back on, improving restoration efficiency.

Clearly upgrading to a smart meter offers many benefits and is the best option for the vast majority of customers. However, for customers who prefer not to have a smart meter, Dominion Energy does offer an opt-out program, with some limitations.

Opt-out limitations:

- Customers must take electric service from Dominion Energy under residential rate Schedule 1. Customers receiving electric service on any time-of-use or demand rate and customers who generate electricity are ineligible due to additional data required for billing and/or operating purposes.
- Accounts must be in good standing without any pending or recently completed (within the last 12 months) adverse credit activity with Dominion Energy.
- As per the Company's *Terms and Conditions for the Provision of Electric Service* as approved by the State Corporation Commission of Virginia, meters must be readily accessible to the Company, as walk-up meter reading will be required on a monthly basis.
- Customers must sign and return the Smart Meter Opt-Out Program enrollment form.
- Customers must allow the Company to exchange the current meter for a non-communicating digital meter. Legacy meters will be exchanged for non-communicating digital meters, as legacy meter reading and meter data processing systems are being retired.

Fees for Smart Meter Opt-Out Program

Due to the fact that additional efforts must be expended to administer the opt-out program, create an opt-out version of the meter, and read the non-communicating meter via walk-up procedures in perpetuity, the following fees will apply to customers who choose to opt out of smart meter implementation based on 2019 cost data:

- One-time initial fee: $84.53
- Ongoing monthly fee: $29.20

Opt-Out fees are subject to SCC approval and subject to revision.

Opt-Out Enrollment, Meter Exchange and On-going Meter Reading Cost Projections

Initial exchange/installation of non-communicating meter

Tasks	Time Spent per opt-out customer	Hourly Rate	Total	Note
Program administration and reporting, customer communications, work order generation/scheduling	0.75	$45.75	$34.31	(1)
Meter order processing, inventory management, shipping	0.5	$42.78	$21.39	(2)
Meter exchange	0.5	$58.55	$29.27	(3)
Credit based upon current costs being recovered in rates			**($0.45)**	
Total			$84.53	

Notes:
(1) Average/combination of Metering Solutions Ops Analyst and Lead Field Metering Analyst; pay grade mid-point, loaded rate
(2) Loaded Hourly Rate of a Shop Meterman
(3) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on average numer of service order completions in a day in 2019

Monthly Fee

Department	Time Spent	Hourly Rate	Total	Note
Meter read	0.5	$58.55	$29.27	(4)
Credit based upon current costs being recovered in rates			**($0.07)**	
Total			$29.20	

(4) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on projected average numer of service order completions in a day post-AMI deployment

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred.

2. 150 days for Customers having a maximum demand below 50 kW during the past year.

3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If a Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.

2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.

3. The Company will acknowledge receipt of Customer's request for the Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) Installation, Removal, and On-going Charges for Non-communicating Meters			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.

2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.

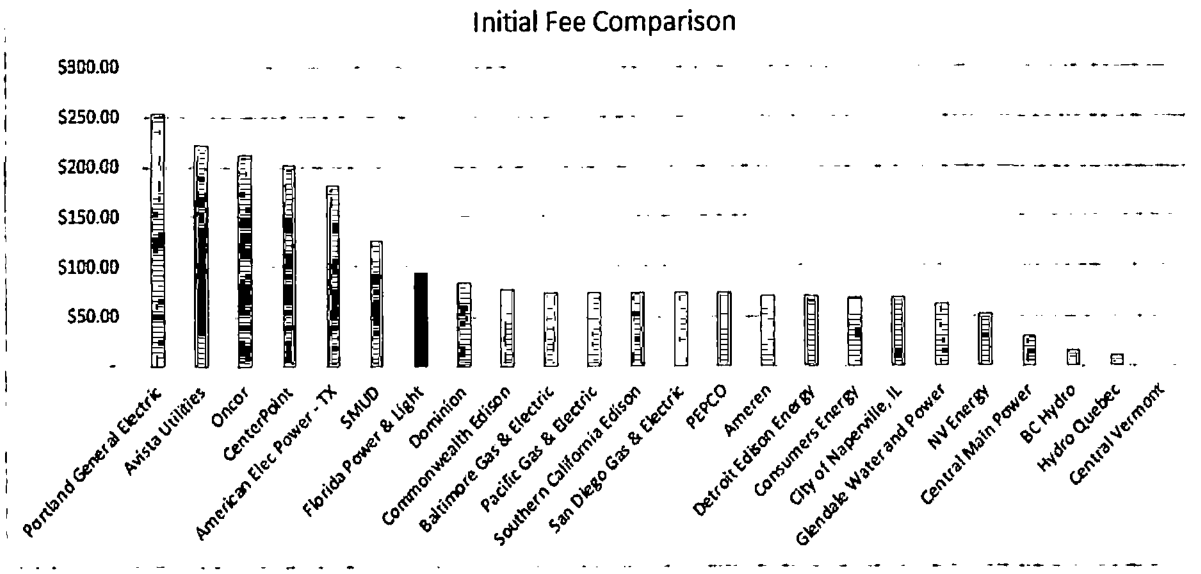
3. The Company will acknowledge receipt of Customer's request for Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

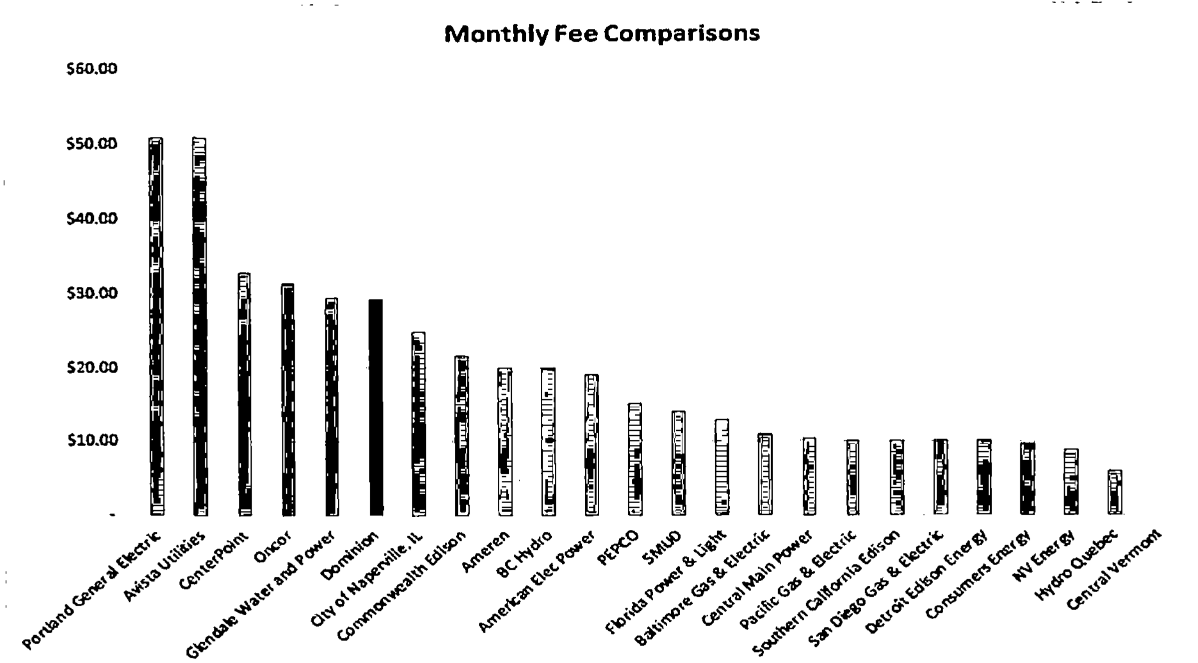
The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) **Installation, Removal, and On-going Charges for Non-communicating Meters**			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

OPT-OUT FEE COMPARISON





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Electric Vehicle Adoption Forecast

Counts (Cumulative)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	25,698	33,855	43,416	54,190	66,678	80,456	95,812	112,423	130,201	149,079	169,159
Navigant Low	18,754	22,296	26,837	32,329	39,147	47,078	56,368	66,860	78,473	91,159	105,010
Navigant High	29,906	41,781	55,409	70,528	87,754	106,564	127,296	149,607	173,280	198,144	224,332
MWh (Annual)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	88,499	116,589	148,806	184,755	226,103	271,322	321,431	375,245	432,661	493,590	558,432
Navigant Low	62,948	74,579	89,166	106,659	128,303	153,304	182,547	215,417	251,666	291,182	334,297
Navigant High	101,749	141,758	186,792	236,401	292,627	353,615	420,719	492,606	568,621	648,250	732,000
MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	32	42	53	66	80	95	111	129	148	167	187
Navigant Low	23	27	32	38	45	53	63	74	86	98	112
Navigant High	37	51	67	84	102	123	145	168	192	217	243

Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite

This tool provides a simple way to estimate how much electric vehicle charging you might need at a city- and state-level.

State Vehicles Results

Start Over

Your Results

In Virginia, to support 169,159 plug-in electric vehicles you would need:

3,778 Workplace Level 2 Charging Plugs

2,614 Public Level 2 Charging Plugs

There are currently 1,093 plugs with an average of 2.0 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

414 Public DC Fast Charging Plugs

There are currently 308 plugs with an average of 3.6 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

Where Do I Start?

Planners may want to prioritize installation of fast charging infrastructure above Level 2 charging.

Build DC Fast First: Establishing fast charging networks that enable long-distance travel, serve as charging safety nets, and provide charging for drivers without home charging is critical to support all-electric vehicles that have no other alternative for quickly extending their driving range.

Build Level 2 Second: EVI-Pro typically simulates the majority of Level 2 charging demand coming from plug-in hybrid electric vehicles, which have the ability to use gasoline as necessary for quickly extending driving range.

Change Assumptions

Plug-in Electric Vehicles (as of 2016): 7,300

Light Duty Vehicles (as of 2016): 7,331,000

Number of vehicles to support 169,159

Vehicle Mix

Plug-in Hybrids 20-mile electric range	15	%
Plug-in Hybrids 50-mile electric range	35	%
All-Electric Vehicles 100-mile electric range	15	%
All-Electric Vehicles 250-mile electric range	35	%
Total	100%	

How much support do you want to provide for plug-in hybrid electric vehicles (PHEVs)?

- ○ **Full Support** *Most PHEV drivers wouldn't need to use gasoline on a typical day.*
- ◉ **Partial Support** *Calculate using half of full support assumption.*
- ○ **Do not count PHEVs in charging demand estimates.**

Percent of drivers with access to home charging 100 %

See all assumptions.

EV Adoption Forecast, Year 2030: 169,159

	New Charging Infrastructure Needed by 2030		
		Workplace Level 2 Ports	Public DC Fast Charging Ports
Row 1	Charging infrastructure needed to support forecasted adoption (Source: EVI-Pro Lite Tool):	3,778	414
Row 2	Less known existing charging infrastructure (Source: Alternative Fuels Data Center):	N/A	86
Row 3	New infrastructure needed by 2030 (Row 1 less Row 2):	3,778	328
Row 4	New infrastructure needed each year (Row 3 divided by 10 years):	378	33

	New Charging Infrastructure Needed during Phase 1B (2020-2021)		
Row 5	Two years of infrastructure - ports (Row 4 multiplied by 2)	756	66
Row 6	Two years of infrastructure - dual port charging stations (Row 5 divided by 2)	378	32.80

Existing Public Infrastructure (ports):	
Public DC Fast Charging	308
Public DC Fast Charging (No Restrictions)	86
Public Level 2	1,093
Public Level 2 (No Restrictions)	248
(No Restrictions) = No access requirements; available 24/7	